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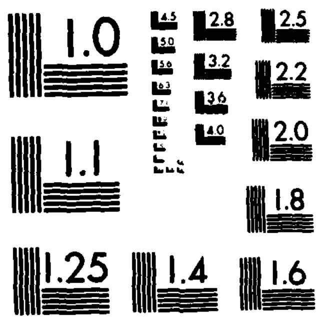

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LOAD MANAGEMENT- METHODS TO REDUCE ELECTRIC UTILITIES PEAK LOADS

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BY

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A REPORT PRESENTED TO THE GRADUATE
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CHAPTER I

INTRODUCTION

1.1 BACKGROUND

The growth of the United States population in the twentieth century brought about a tremendous increase in the consumption of electrical energy. In the early years, the low cost and large abundance of fossil fuels made the use of electrical energy highly desirable, and many Americans were encouraged by the electric utilities to increase their usage. In the early 1960's, however, utility companies began incurring increased costs due to both capital investment costs in new generating equipment and higher fuel costs. The development of electrical appliances and more labor saving devices began to place additional burdens on electric utilities. Peak loads continued to rise dramatically and utilities were hardput to provide adequate generating capacity to meet these new peaks. One method that was developed to defer some of the costs of new generating equipment is now referred to as load management or peak shaving.

Load management programs include reduction in total energy usage as well as the shifting of peak loads from one time of day to another, the latter being the most predominant feature. In the early years of load management, Michigan electric utilities installed time clocks on water heaters that were preset to turn off the water heater elements for four hours during peak load periods. This system simply deferred the water heater load from a peak period to a valley, or period of low

electric demand. One of the problems with this system was that it deprived the customer of electricity to the water heater whether the peaks occurred or not. Later systems were developed that would shut the water heater off only if it were necessary to avoid peaks. In addition, other deferrable loads have been considered including electric space heating, central air conditioning, irrigation pumps, and some industrial loads.

Load management had such potential impact that the the federal government became involved. In 1975, the Federal Energy Administration's Office of Energy Conservation and Environment entered into cooperative agreements with agencies of state and local government to support "demand management" projects for electric utilities.[1] The largest impact came in 1978 when the Public Utilities Regulatory Policies Act (PURPA) was enacted which required state regulatory commissions and many electric utilities to consider load management options. The U.S. Department of Energy has provided funds for research to seek improvements by which the existing energy resources can be utilized more efficiently. These improvements include more efficient conversion of fossil fuel to electric energy, more efficient end utilization of electric energy, and an electrical energy market in which consumers are encouraged to make sound economic decisions regarding their electrical consumption patterns.[2]

1.2 SCOPE OF REPORT

This report provides an analysis of load management, which encompasses the goals described above. Included in the analysis is the relation of utility rates to electrical consumption, various plans

for load management, an evaluation of load management systems and devices, and some methodologies for assessing load management. Although time of use rates may be an integral part of load management, this report will only briefly discuss the facets of this indirect method of load control. The purpose of this report is to acquaint the reader with the concept of load management and to assist in the formulation of load management options. All costs presented in this report are approximate costs in 1979. The reader should use caution when updating costs due to the decreasing costs of microelectronic equipment.

CHAPTER II

UTILITY RATE STRUCTURES AND LOAD MANAGEMENT CONCEPTS

2.1 UTILITY RATE STRUCTURES

During the late 1960's and early 1970's, electric utility companies began experiencing difficulties in meeting the growing demand for electrical power generation due to the substantial costs of financing and operating new power generation plants. As a result, electric utilities throughout the U.S. significantly reduced planned construction and began encouraging users to reduce their consumption of electric energy in order to reduce consumption of fossil fuels. Deteriorating economic conditions, high interest rates, high fuel prices, inflation, and regulatory lag combined to adversely affect the financial viability of electric utilities. This affected their ability to attract necessary capital to finance the required construction programs.[3] In order to still meet the increasing demand for electrical energy, utilities had to continue to raise their rates to recover capital costs and fuel purchases.

State and federal public utility commissions fix the rates of privately owned electric utilities based upon the overall revenue requirements of each utility. Since utilities essentially have no direct competition, the government regulates rates to prevent utilities from taking advantage of their monopoly positions. The regulatory commissions usually determine the total revenue requirements, leaving the design of the rate schedules to the utilities.[4] Utilities use more

than one rate schedule for different end users due to demand and rate of energy charges. Demand and rate of energy charges are both related to load factors, which are defined as the ratio of average usage to peak usage with 100 percent being the highest factor. The demand charge is determined by the fixed costs of installing and maintaining plant capacity to meet the maximum load and is measured in kilowatts (kW). The rate of energy usage charge is based upon the variable costs to operate the plant, mainly fuel, and is measured in kilowatthours (kWh).[5]

Industrial users, who have fairly constant load factors, are billed using both demand and rate of energy usage costs. These two costs are determined by installation of two separate meters at the user's facility. Due to the high capital costs to install an additional demand meter at residential buildings, utilities will bill residential customers based upon one meter reading which determines the rate of energy usage; however, the utilities incorporate an additional demand charge into the residential rates based upon average load factors developed by the utilities. This insures that the demand charges are distributed throughout all end users' bills.

An example is provided to illustrate billing rates:

An industrial customer requires 240 kWh per day with a steady load of 30 kW. A residential customer requires 240 kWh per day with a peak load of 30 kW. The utility then requires 60 kW generating capacity (plus standbys) to meet the peak load. The demand charge for both customers would then be the same. The rate of energy usage charge would be different, however, due to the fact that the industrial user only operates 8 hours a day while the residential user is on a 24 hour cycle. Thus, the residential user requires the utility to operate 24 hours per day to provide the same amount of energy that could have been more economically provided during an 8 hour period.

Due to these reasons, and coupled with the fact that losses due to transmission and voltage changes are less with industrial customers, residential customers generally pay more than industrial (but less than commercial) for the same amount of power.[6]

2.2 LOAD CONTROL CONCEPTS

Load control is a concept by which the electric utility seeks to level out the peak loads and to more economically utilize existing equipment. Most primary electrical generating equipment uses coal, which is a relatively cheap source of fuel. When loads begin to rise, secondary equipment is put on-line to generate the additional demand requirement. These secondary units, or intermediate and peaking units (IPU), usually use oil for fuel and are more expensive to operate. The increased costs due to peaking units are included in the utility charges to the end users. One of the goals of load management is to defer the use of IPUs, thus reducing costs and the use of precious fuels.[7]

Utilities would like to have the highest load factor possible in order to eliminate having idle generating capacity during off-peak hours. Ideally, the utilities would like to have plants running at full capacity all of the time, without any need for additional equipment except standbys for maintenance and emergencies. Energy planners have suggested means such as load curtailment, price signals, and load management to achieve this goal.[8]

2.2.1 Load Curtailment

Load curtailment refers to an actual reduction in the use of energy through several means including the reduction of lighting and HVAC loads, controlling equipment usage, and using more efficient electric appliances and equipment. Load curtailment reduces both

generating requirements and the consumption of fossil fuels needed to generate electricity. Load curtailment can be very costly due to retrofit of existing equipment and may not be effective due to reliance on the voluntary nature of the customer.[9]

2.2.2 Price Signals

Price signals refer to systems which implement time of use rate schedules. Time of use rates essentially consider the cost of generating electricity during peak periods. Base loads are charged according to the costs of operating primary equipment. When IPUs are brought on-line during peak periods, a meter or other similar device in the customer's building indicates that the rates for that time period are higher. Price signals require an additional meter or installation of a dual control meter and may not be cost effective due to the capital cost and installation and maintenance costs. Price signals also have other problems. Customers may ignore the signals regardless of the costs and demand energy when they need it. In addition, if all customers watch for higher signals, they may be able to shift the peak from one period to another and not eliminate the problem. Utilities considering a dual metering system face the difficult task of educating the customers. The need for simplicity in rate schedules can sometimes lead to problems in implementation. Customers having difficulty understanding rate schedules may be apprehensive in allowing the units to be installed.[10]

2.2.3 Load Management

Load management is slightly different from load curtailment and price signals. Load management does not necessarily reduce the overall

energy requirements, it mainly defers high demands from one time of day to another. Generally, the utility controls the times when loads are to be deferred. The load management programs are mainly voluntary, and credits or lower rates are offered to those customers who have load control devices installed in their homes or plants. Price signals may be incorporated into a load management program.[11]

The impact of load management depends largely on how it affects each end use. For example, if the total electric energy used to heat water is a small fraction of total demand, the impact of controls will be small even if they are used by all customers who require hot water. During research and development, planners should examine the order of magnitude of possible hourly demand shifts and determine its effect on daily and seasonal variations in electricity demand. Differences in climate and appliance use can have significant impacts on demand patterns.

There are several strategies for achieving load management. On the customer's side of the meter, thermal energy storage devices may be installed, or control devices may be installed on appliances that consume large amounts of energy. The devices may be indirectly or directly controlled by the utility. Indirect controls are similar to price signals, where there is an economic incentive to the customer to voluntarily shift their pattern of electricity use. Direct control consists of devices that are controlled by the utility that interrupt the use of some appliances during peak loads. On the utility side, options exist such as pumped hydroelectric storage or utility battery storage. This report will not discuss these latter two forms of load management.

Load management may be applied to customers in the residential, commercial, industrial, and agricultural sectors, as well as to distribution utilities that purchase wholesale electric power for resale to customers. The loads most often considered for load management are listed in Table 2-1.

Table 2-1 Customer Loads Most Often Considered for Load Management

- Residential
  - Water heaters
  - Central air conditioners
  - Central space heaters
  - Swimming pool pumps
- Industrial
  - Nonessential loads
- Municipal
  - Water pumping
- Commercial
  - Water heaters
  - Central air conditioners
  - Central space heaters
  - Nonessential loads
- Agricultural
  - Irrigation pumping

(Source: Benefits and Costs of Load Management: A Technical Assistance and Resource Material Handbook, Argonne National Laboratory, June, 1980, p. 8)

CHAPTER III

THERMAL ENERGY STORAGE DEVICES

3.1 PURPOSE OF THERMAL ENERGY STORAGE DEVICES

The objective of load management is to reduce the growth in utility peak demand in order to reduce the construction of new generation and transmission equipment and to more effciently use existing equipment. To significantly reduce peak demand, substantial amounts of deferrable customer loads must exist. Water heating, space heating, and air conditioning are examples of deferrable or interruptible loads. These loads can be shifted from peak periods to off-peak periods on a repetitive or daily basis. One method for shifting these loads is through the use of thermal energy storage devices which take advantage of charging during off-peak periods.[12]

3.2 TYPES OF THERMAL ENERGY STORAGE DEVICES

There are several types of storage devices commercially available in the U.S. today. They are mainly of the storage heating type and are installed on the customer's premises. If the storage devices are adequately sized, the customer experiences no inconvenience even though the utility may control the storage unit. Storage heating technologies have been used widely in Europe. The major types are described herein.

3.2.1 Static Room Storage Heaters

This type of heater consists of a ceramic brick storage core which is heated by electric resistance heating elements. The units

are charged during off-peak periods by using electricity to heat the core. Controls are set by the user for a full or partial charge depending on weather conditions. After charging, the heat stored is then released for room heating by thermal convection and radiation.

One problem with this type of heater is that it tends to overheat a room at the beginning of its heating cycle and underheat towards the end of its cycle. In addition, ceramic heaters cannot be economically made to sufficient size for heating large room spaces. These units are generally used in Europe for heating areas such as bathrooms and hallways. This type of heater may not find wide popularity in the U.S. due to central space heating which already exists.

3.2.2 Dynamic Room Storage Heaters

This type of heater is similar to the static room storage heater except that thermostat controls and fans are an integral part of the unit. The amount of thermal charge stored is adjusted automatically by a temperature sensor. A bridge circuit is activated by temperature sensors that monitor changes in the outside temperature and the residual heat in the storage core when the charging period is reached. The unit is then activated according to the demand that will be required when charging is completed. The heat from the unit is released by thermal radiation from its case and forced convection by the fan. A room thermostat controls the unit by using a damper that allows only a portion of the air drawn from the room to pass over the core, thus controlling the amount of heat in the room.

Dynamic room storage heaters provide close temperature controls and can compensate for additional heating in the room due to lighting

and appliances. These heaters can be used to heat an entire home, however, they are fairly large and heavy. Both new construction and retrofit applications can be considered since no extensive structural work is needed to install the units.[13]

3.2.3 Central Ceramic Storage Heaters

These units are similar to the dynamic room storage heaters except they are very large and use a central duct system to heat each room of a house from a central location. These units weigh over 3000 lbs for an average sized heater and require a location that can withstand heavy loading. One advantage is that these units may be placed in a separate room, thus utilizing the heated air in the room for recirculating through the unit into the other rooms.

One firm in the U.S. has developed a direct heating/storage heating unit which utilizes direct resistance heating during off-peak and charging cycles, then switches to storage heating during peak load periods. Although these units are currently being marketed for residential use, there have been suggestions towards some industrial purposes. One industry installed a unit in a large warehouse. Resistance heating mats were installed beneath a 6 inch concrete floor in a 12 inch bed of sand. The mats were heated during off-peak periods, storing heat in the concrete and sand. The building was then heated by radiation of the stored heat.[14]

3.2.4 Hydronic Central Storage Heaters

Hydronic central storage systems are closed systems which consist of a tank that has electric resistance heating coils immersed in water stored inside. The system is closed to allow higher pressures and temperatures inside the tank and to avoid continually running water through the tank that might corrode it due to salts or dissolved

oxygen. The water is heated to temperatures in the range of 240-285 degrees F. during off-peak hours, then is circulated through coils over which air or water is drawn. The secondary system of air or water is used for space heating or domestic hot water. The size of the heating element determines the time between charging periods and is sized to permit use of the system during charging.

The Megatherm corporation of East Providence, Rhode Island makes hydronic storage units for residential use. The units consist of a sealed and insulated 212 gallon water tank, about 93 inches long, weighing about 980 lbs excluding water, and can fit through a 30 inch door prior to installation of insulation and an outer metal shell. The system can be used in new construction or as a retrofit.

Hydronic storage can be used to heat and cool commercial buildings. One such installation is in a 3600 SF Minnetonka, Minnesota building. Installation consisted of two 40,000 gallons standard fuel oil tanks covered with 2 inches of polyurethane and buried. The tanks stored water heated to 200 degrees F. during the winter and cooled to 45 degrees F. during the summer. The water was brought to these temperatures using a 400 kW electric boiler and a 65 ton chiller during off-peak hours. The storage capacity provided 24 hours of heating and 9 hours of cooling.[15]

3.2.5 Storage Air Conditioning

Storage air conditioners are still in the development stages for residential use. This method utilizes an air conditioner compressor during off-peak hours to chill water or create a water/ice mixture which is stored in insulated tanks. During peak hours, the

chilled water is circulated through coils and air is blown over them to cool the space. This system is in use in some commercial buildings. Average residential uses would require storage tanks of about 250 gallons. The relatively large size of such units is currently one of the main problems of this system.[16]

3.2.6 Hot Water Storage

This method consists generally of installation of a timer on an electric resistance water storage tank heater which is set to charge during off-peak hours. This is one of the most common and simple forms of energy storage. It is recommended that water heaters be sized to provide adequate amounts of hot water for all members in the family during one heating period. Most utilities recommend an 80 gallon capacity storage tank to insure no inconveniences are experienced.

The above methods are ones which have been developed and are in use. There are numerous other methods, particularly those involving air conditioning, which are under development. These systems may be directly controlled by the utility or by the consumer with guidance from the utilities. The following chapter discusses direct utility control, which is the best approach to load management.[17]

CHAPTER IV

LOAD CONTROL AND COMMUNICATIONS SYSTEMS

One option available to utilities for load management is direct control of consumer appliances or equipment through the use of load control and communications systems. These systems either remotely or locally control end use devices.

4.1 LOCAL LOAD CONTROL SYSTEMS

Local control devices depend upon timing or physical sensing devices which regulate electricity usage. Timing devices are installed on the appliances and are preset to interrupt electrical usage during certain periods of the day. As mentioned previously, one of the problems with timers is that they may interrupt service unnecessarily. In addition, timers do not allow the utilities to react to emergency conditions where rapid drops in electric power are required to offset system overloads.[18]

4.2 REMOTE LOAD CONTROL AND COMMUNICATIONS SYSTEMS

Remote control systems generally consist of a number of load control and communications (LCC) devices. There are various types of LCC systems commercially available, and most utilities are using some type or combination to monitor and control loads. The types of LCC systems include ripple control, power line carrier control, radio, and telephone control.[19] These communications systems are either unidirectional or bidirectional, depending upon the

sophistication required by the utilities. A unidirectional system transmits a command signal one way from the utility to the control device. A bidirectional system both transmits a command signal and monitors various segments of the distribution system.[20]

All LCC systems consist essentially of three components: the control center, the communications system, and the end control device. The control center is the nerve center of the system and is usually computer based. The communications system is based either on telephone or radio communications from the control center to points in the distribution system which send signals to the end control devices. End control devices perform the actual shut-off of electricity to appliances or switching functions in the distribution system. Each LCC system operates by sending signals in some form to the end control devices in order to shed some loads. Separate signals are transmitted to activate and deactivate the end controls in the system. Radio is the most commonly used method for communications systems; however, other systems are gaining in popularity.[21]

Load control and communications systems have three basic functions which can be performed: 1) general load control by interrupting service using remote control switches 2) communication with other systems or devices and 3) distribution automation. The applications of each function are outlined in Figure 1.

Distribution automation is one function that may be used by the utilities. Some utilities will lower the voltage in the distribution system only as an emergency measure. Remote meter reading is one function that may not be economical to a utility. For example, a rural area might not be economically suitable since people read their own meters. In a city, remote meter reading might be more appropriate due

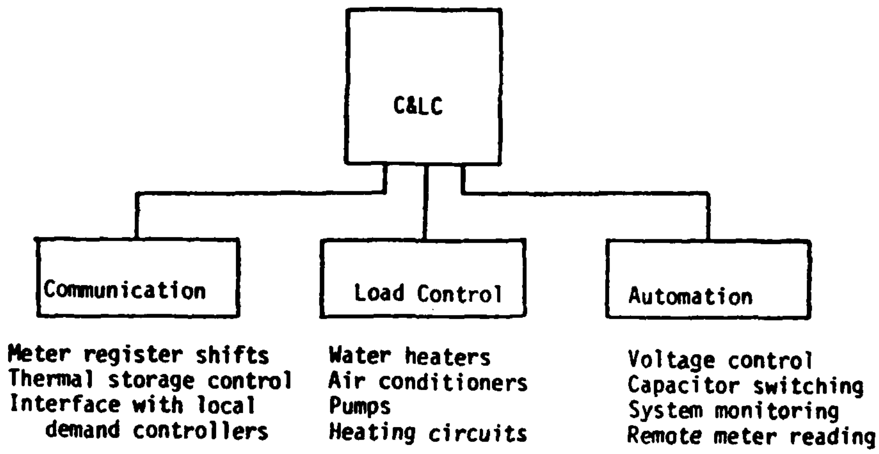

Figure 1. Applications of Load Control and Communications Devices

(Source: Evaluation of Load Management Systems and Devices, EUS Inc., Pittsburgh, PA, June, 1980, p.1-4)

to the large numbers of meters. The following pages describe some of the main load control and communications systems in use. Other systems exist which vary in signal generation and hardware, but are still in the experimental stages of development.[22]

4.2.1 Ripple Control System

This method has been widely used in Europe and other parts of the world for over 30 years. Estimates indicate that about 10 percent of the total generating capacity is under ripple control. A ripple control system uses the existing transmission network to send signals to end control devices. The system works by using a transmitter which superimposes a frequency impulse in about the 200-1500 Hz range on the normal 60 Hz line voltages. These low frequencies are used since they can be transmitted over long distances without attenuation. In order to insure an acceptable signal to noise ratio, short duration frequency impulses must be generated at high voltages, about 0.1 percent of the supply voltage.[23]

Ripple transmitters can be located anywhere in the transmission system, depending upon the economics and functions desired by the utility. For example, a distribution automation function such as capacitor bank switching might be best performed by locating the transmitter at a high voltage level in the network and the receivers at distribution substations. Load management functions are best performed by locating transmitters at distribution substations and receivers in the customer's home. Most ripple systems are unidirectional; however, the Green Mountain Power Company in Vermont is using a bidirectional system in two local schools. This system both controls and monitors electric heating circuits.[24] In this application, the return signal from the school gives an indication of total demand.

When this demand reaches 80 percent of the preset load, the heating load is recycled and different heaters are turned off for periods of 15 minutes at a time to increase the overall diversity of the load.[25]

A typical unidirectional ripple system is shown in Figure 2. Costs for a unidirectional ripple system varies according to the saturation level of receivers in the system. Attempts should be made to maximize the number of receivers on each transmitter. Costs will be higher for systems that have fewer receivers on each transmitter. At high receiver saturation levels, the cost of the system is mainly governed by the cost of the receivers. For low saturation systems, the costs are mainly governed by the cost of the control center and its related hardware. The three major cost components of an LCC system are 1) the cost of the receiver switch itself 2) the cost of installation of the receiver switch and 3) the total installed costs of all other equipment, including the control center. The total of these three costs are divided by the number of receivers installed to obtain a per point cost basis.[26]

Ripple systems are a relatively new innovation in load management in the U.S.; however, two utilities have implemented the system and obtained fairly reliable cost estimates for varying receiver saturations.[27] Figures 3 and 4 present these cost relations for the Minntoka Power Cooperative and the Green Mountain Power Company.

The Minntoka Power Company services a large area in South Dakota and Minnesota. The large area required high powered transmitters which cost considerably more than low power transmitters which are used in fairly small service regions. The high cost of central

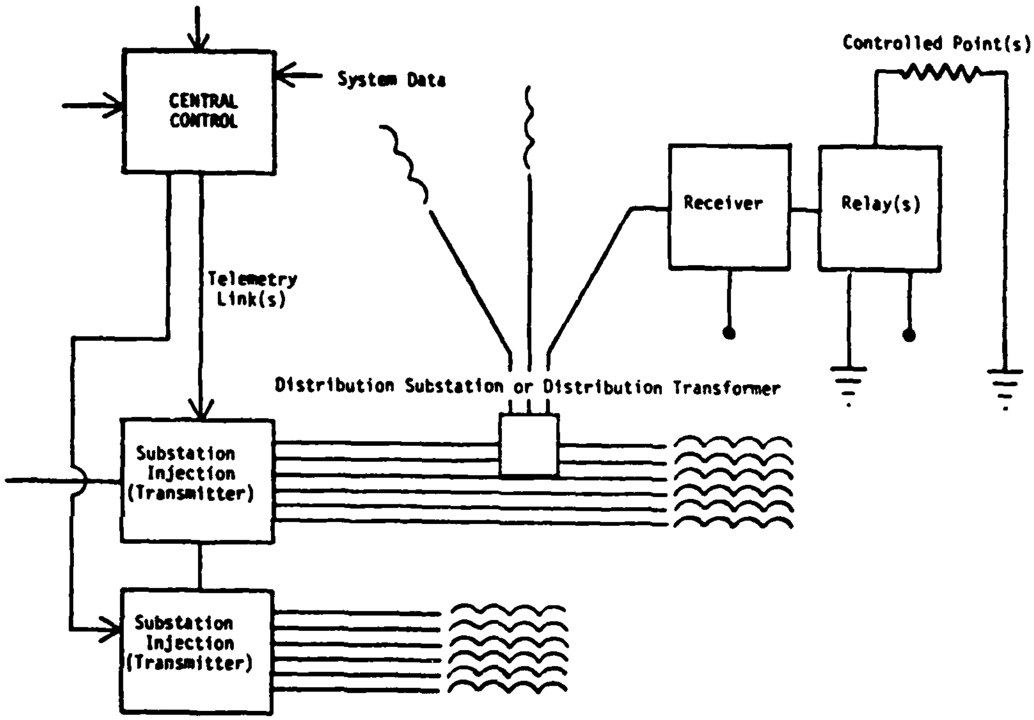

Figure 2. Unidirectional Ripple Load Control and Communications System Block Diagram

(Source: Evaluation of Load Management Systems and Devices, EUS Inc., Pittsburgh, PA, June, 1980, p.1-35)

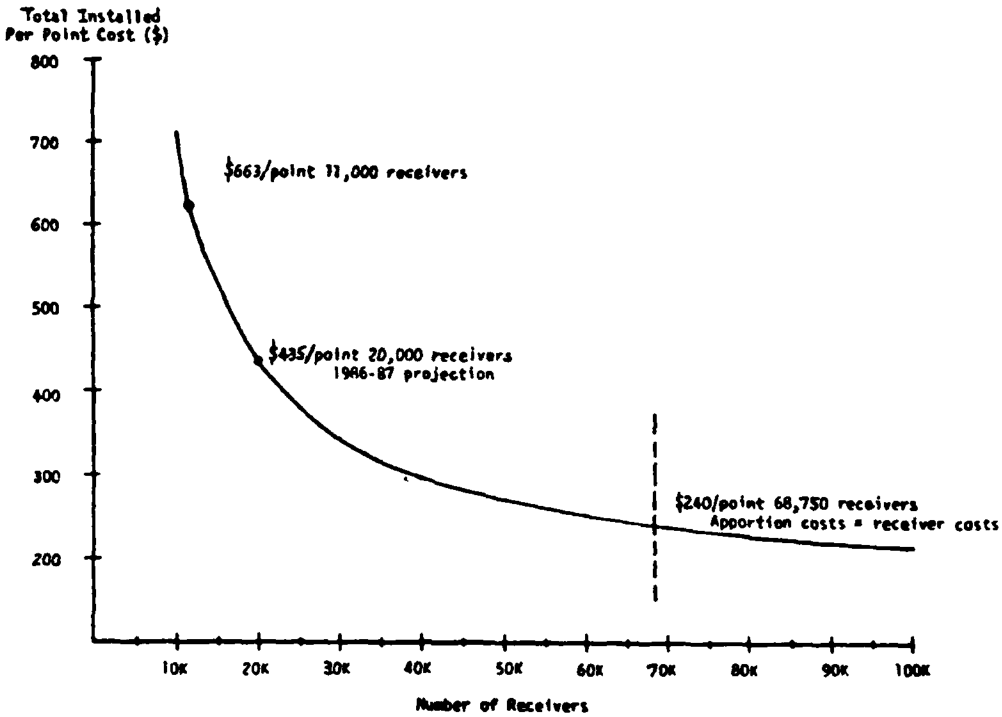

Figure 3. Minnkota Power Ripple Control Total Per Point Cost as a Function of Receiver Saturation

(Source: Evaluation of Load Management Systems and Devices, EUS Inc., Pittsburgh, PA, June, 1980, p.1-40)

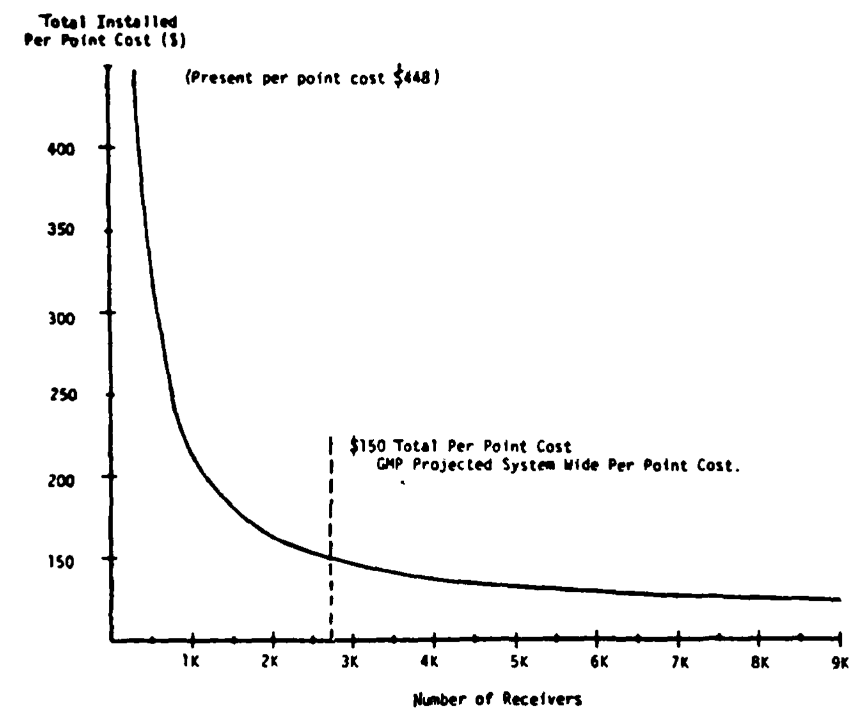

Figure 4. Green Mountain Power Ripple Control Total Per Point Cost as a Function of Receiver Saturation

(Source: Evaluation of Load Management Systems and Devices, EUS Inc., Pittsburgh, PA, June, 1980, p.1-44)

control equipment and receivers coupled with a low population density in the region combined to give a high per point cost for the system. These per point costs would drop as more receivers were installed, but only to the limit of the number of customers served by the utility.[28]

The Green Mountain Power Company has a smaller service region and a smaller number of people served. The ripple system consists of only one transmitter which currently controls 300 receivers. The system is experimental, however, the potential exists for a larger system due to a high population density. The graph in Figure 4 is extrapolated to show the potential per point cost of the system. Green Mountain Power expects that when 3000 receivers are installed in the network, the total per point cost will drop below $150. This $150 per point total cost figure is the one that the utility is using to measure the cost effectiveness of the system. Beyond that point, further receiver saturation realizes only marginal benefits in the form of lower per point costs.

Ripple control systems have a high reliability both in operation and maintenance as well as transmission coverage to all receivers. Utilities considering this type of system should be aware of potential costs associated with low population densities and the total number of customers served by the utility. Each utility has its own distinct characteristics which should be evaluated in deriving per point costs.[29]

4.2.2 Power Line Carrier Control Systems

The power line carrier control systems are similar in principle to the ripple control systems in that they transmit signals along transmission lines. The main difference is that they use higher

frequencies in the range of 5-300 kHz (compared to 200-1500 Hz for ripple control). This system is favored by U.S. manufacturers because it takes less power to provide an impulse with similar signal to noise characteristics as a higher powered, lower frequency signal. In addition, modern solid state technology lends itself to high frequency, low power signals in small receiver and transmission equipment.[30]

Problems associated with this system are 1) higher transmission losses in transformers 2) impedance mismatches in capacitor banks and 3) requirements for amplifiers in the system. All of these problems can be overcome by changing electrical configurations at transformer and capacitor banks, and by operating at the lower range of about 5 kHz. When operating at lower frequencies, it is somewhat difficult to discern any difference between power line carrier and ripple control systems.[31]

The additional hardware costs to overcome transmission problems tend to offset the lower costs of the transmission equipment in a unidirectional system. In a large bidirectional system, the economic advantages of lower transmitter costs can play a much greater role. This is due to the fact that the end control device acts as both a receiver and a transmitter, or transceiver. The low cost of the transceivers can provide more benefits in the way of remote meter reading, verification of reception of commands, and utility distribution monitoring. The justification of these added capabilities must be evaluated according to the control needs of the utility. Generally, the greatest benefit derived from an LCC application, either uni- or

bidirectional is direct control of end use devices. Benefits derived from additional functions such as remote monitoring are generally incremental which must be weighed against the additional costs of increased capacity. Many utilities are interested in two-way communications and are using some mix of unidirectional and bidirectional communications. The two types of systems are depicted in Figures 5 and 6.[32]

Costs for a power line carrier control system are still being evaluated because this system has not been extensively employed elsewhere in the world. Various manufacturers of these systems have developed per point costs based upon cost information for experimental systems already installed. The per point costs are relatively different from those of the ripple control systems due to the added cost of equipment to overcome high frequency problems and the lower cost of solid state control devices. The total per point cost as a function of receiver saturation is presented in Figure 7.[33]

4.2.3 Radio

Unidirectional radio systems are the simplest and most widely used method of load control and communications in the U.S. today. These systems use FM radio transmitters strategically located throughout the service area to transmit encoded signals from the utility to radio receiver switches at the customer's location. The switches perform similar functions as the other types of systems' receivers, that is to turn appliances on and off.

Most of the systems in use today are manufactured by Motorola. Motorola receivers are preprogrammed to disconnect appliances for about 7 minutes when commanded to do so by the central control. After 7 minutes the appliance is automatically re-energized unless another

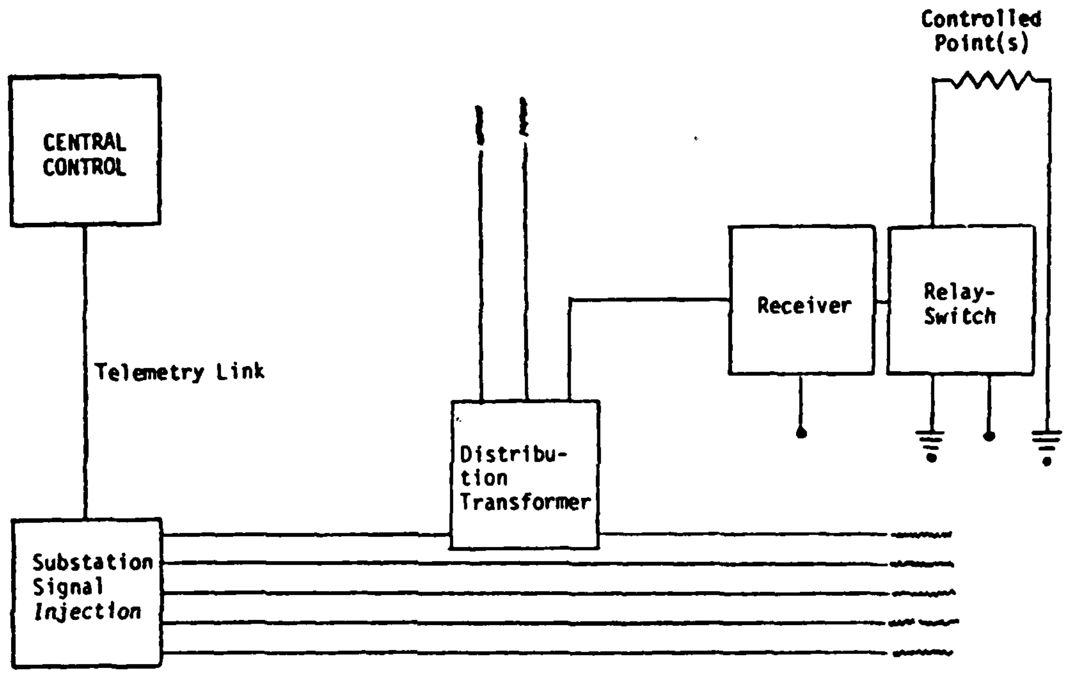

Figure 5. Unidirectional Power Line Carrier System Block Diagram

(Source: Evaluation of Load Management Systems and Devices, EUS Inc., Pittsburgh, PA, June, 1980, p.1-50)

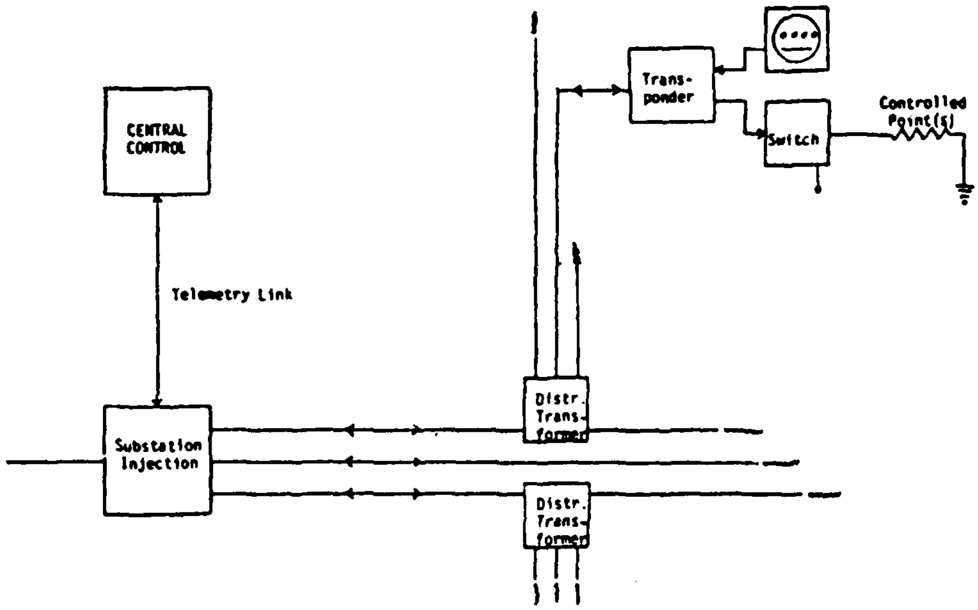

Figure 6. Bi-directional Power Line Carrier System Block Diagram

(Source: Evaluation of Load Management Systems and Devices, EUS Inc., Pittsburgh, PA, June, 1980, p.1-51)

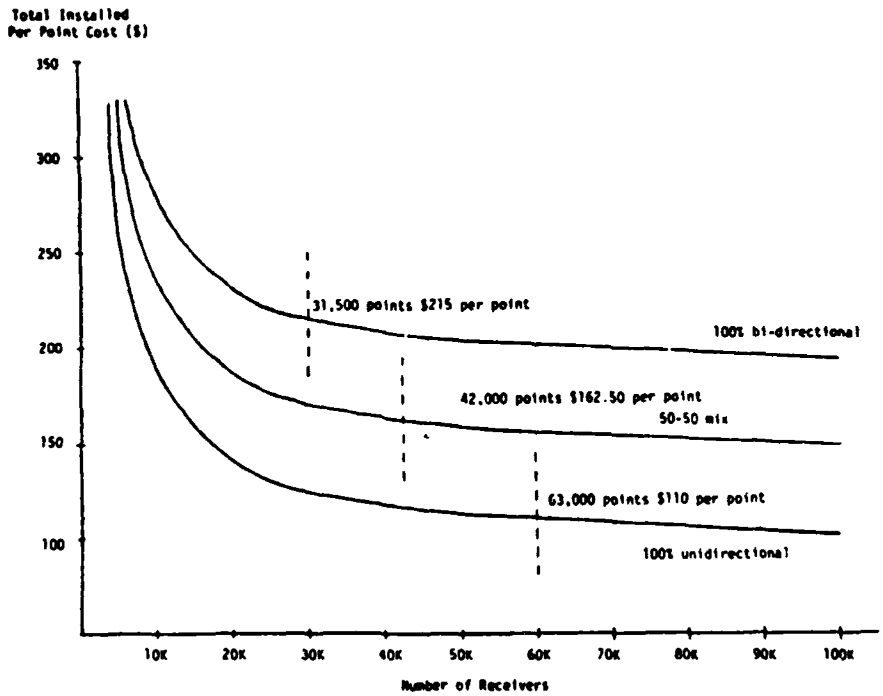

Figure 7. Power Line Carrier System Total Per Point Cost as a Function of Receiver Saturation

(Source: Evaluation of Load Management Systems and Devices, EUS Inc., Pittsburgh, PA, June, 1980, p.1-58)

signal is sent to delay re-energization. In this fashion, the appliance could conceivably be disconnected all day. In order to avoid long outages for the customers, the radio system operates using ten discrete tone-coded signals. Thus, 10 percent of the peak load that is controlled can be deferred for 7 minute periods, alternating throughout all controlled customers. The radio receivers responding to any one tone code are distributed randomly throughout the service area. The tone signals are generated randomly by the central control unit. If an emergency arises, there is a 'scram' program which can permit the utility to drop 100 percent of the controlled load within a few seconds.[34]

A typical radio control system consists of a central control unit, a base station transmitter, and remote receivers. The central control unit is a computer with an identical back-up computer interlocked to prevent outages on the system. This unit monitors load information and compares it to projected data. If the actual load exceeds the projected load, the computer recommends the amount of load to be shed. If programmed to do so, the computer will shed the load automatically and check the integrity of the communication system. Figure 8 depicts a typical radio control system.[35]

The base station transmitter is linked to the central control unit via telephone line or microwave. The transmitter can generate a number of control tones within its bandwidth. Each tone provides controls for various system functions. For example, the Detroit Edison Company uses ten tones for water heater controls, one tone for voltage control at substations, and four tones for air conditioners.

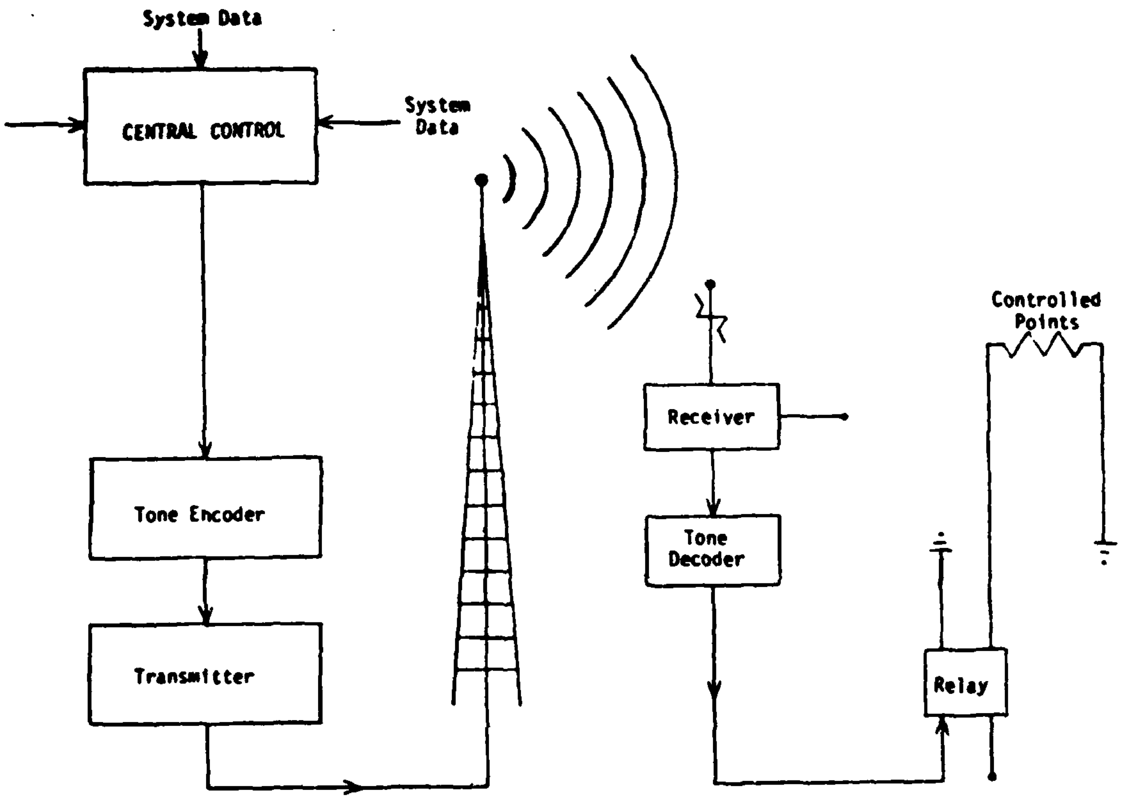

Figure 8. Unidirectional Radio Load Control and Communications System Block Diagram

(Source: Evaluation of Load Management Systems and Devices, *EUS Inc., Pittsburgh, PA, June, 1980, p.1-19)*

The transmitter sends a test signal periodically to the central unit, which determines whether the transmitter is functioning properly. If the central unit determines that the base station transmitter is not functioning correctly, it will alert maintenance personnel. Base station transmitters are distributed throughout the area to insure that each receiver can receive signals from at least three transmitters.[36]

Of the over 275,000 radio receiver switches in use today, over 90 percent control water heaters. The next largest controlled load is air conditioners, followed by irrigation pumps, heating circuits, and other loads. Although mainly unidirectional, radio systems are now being developed for bidirectional systems which will include dual register meter shifting, peak alerting devices, control of thermal storage devices, and some distribution automation functions.[37]

One of the main problems with radio systems is that they are sensitive to terrain. It may be more expensive to control loads in a mountainous area due to the sensitivity of FM signals. Radio systems are otherwise very reliable and do not pose any large maintenance problems. Figure 9 identifies some of the utilities that are currently using radio control systems.

The per point cost for a radio system is mainly dependent upon the size of the system, delivery requirements, number of transmitters, number and types of receivers, redundancy of the system, sophistication of the central control, and telemetry costs. From data accumulated from various utilities and manufacturers, a per point cost versus receiver switch saturation graph has been derived, as shown in Figure 10.

The curves in Figure 10 represent the typical ranges of per point costs for various utilities and have been extrapolated to consider

Utility	Control Points
American Electric Power	120
Arizona Public Service	110
Arkansas Power & Light	6K
Buckeye Power	41K
Carolina Power & Light	225
Central Illinois Light	120
Central Maine Power	120
Cobb EMC	12.5K
Dayton Power & Light	92
Detroit Edison	200K
Duke Power	96
Florida Power	150
Kansas Gas & Electric	115
Lumbee River EMC	8K
Missouri Power & Light	298
Nebraska PPD	2.5K
Northern States Power	42
Otter Tail Power	263
Pacific Gas & Electric	950
Shenandoah Valley	2500
Sulphur Springs Valley	18
Walton EMC	8K
York County	103

Figure 9. Utility-Sponsored Radio Control Projects

(Source: Evaluation of Load Management Systems and Devices, EUS Inc., Pittsburgh, PA, June, 1980, p.1-20)

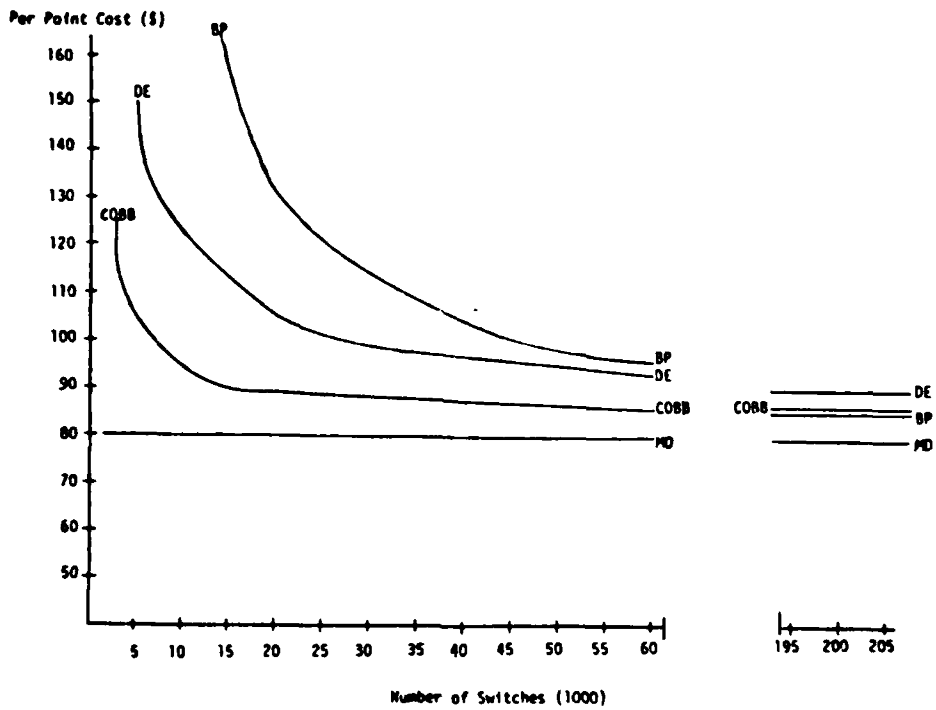

Figure 10. Extrapolated Per Point Costs as a Function of Switch Saturation for Various Utilities* Using Radio Control Systems

(Source: Evaluation of Load Management Systems and Devices, EUS Inc., Pittsburgh, PA, June, 1980, p.1-27)

* BP = Buckeye Power
DE = Detroit Edison
COBB = Cobb EMC
MO = Missouri Power and Light

extreme saturation. A basic single function switch costs about $85 installed, hence it can be seen from the graph that the total system per point cost becomes insensitive to all but the cost of a single function switch beyond a certain saturation level. Although multi-function switches are available, most utilities have found it cheaper to install two single function switches in a home rather than pay an electrician to wire two appliances into one multifunction switch.

4.2.4 Telephone Control Systems

Telephone control is a potential system that may be used for load management and communications. Currently, the most commonly used telephone systems monitor meter readings is a one-way link to the utility. Telephone systems for control are considered to be too costly by utilities because of the high cost of leased lines. The utilities are not in direct control of the entire system, which may lead to serious conflicts between the utilities and the telephone company if emergencies arise.[38]

4.2.5 Demand Control Systems

As discussed earlier, utilities bill their commercial and industrial customers on the basis of demand and energy charges. Demand is normally measured by a separate meter that measures peak loads and shows the maximum kilowatt load connected for a 15, 30, or 60 minute period during the month. The demand charge basically reflects the capital equipment costs of power generation, while the remainder of the bill reflects variable costs based upon kilowatthours used. With current rate structures, it behooves a commercial or industrial customer to have a high load factor, ie. a steady load throughout

the day. There are now demand control systems commercially available that can be used by customers to limit demand and improve load factors.[39]

The demand control system (DCS) operates by controlling secondary loads in a preprogrammed order of increasing priority as peak demand is approached. Some of the loads may be deferred to a later time, some may not be restored at all except by operator intervention. Besides limiting maximum demand, the DCS can lower the cost of installing switchgear, since switchgear capacity is reduced. The DCS may also be used when emergency standby generators are required at particular locations. When used in this manner, the DCS can control the peak demands, thus reducing the required capacity of standby equipment.

The DCS is installed at the customer's location, and monitors power input to the installation. It has a preprogrammed load forecast that it continually compares to the actual demand. When the demand approaches the limit, the DCS begins to remove loads that can be deferred such as thermal storage devices, air conditioning, metal melting kilns, and some glass manufacturing processes. The loads that are deferred are done so in priority order, which is set by the customer's plant engineers and management.[40]

Different demand control systems are available which vary according to the complexity of control desired. One of the more complex systems that is used at many locations is the IBM Remote Power Management SYSTEM 7. This system may be used to control demand at various sites. The functions performed by this system include:

1) Centralized control, permitting load control throughout the company.

2) Load shedding

3) Dynamic balancing, permitting effective use of heating, air conditioning, and ventilation.

4) Providing system reports that identify energy usage in various locations and locates high energy usage areas.

5) Comparing rates of consumption to targets.

6) Sequencing time of day usage according to advantageous utility rates.[41]

One of the earlier demand control systems was implemented in Los Angeles in 1977 due to rising electricity costs for various industries. Earlier, the Department of Water and Power had initiated an ordinance which limited electricity use due to low oil reserves. In response, commercial and industrial facilities cut back consumption by about 30 percent. Instead of lowering kilowatt costs, the DWP increased their rates. This phenomenom occurred because the DWP decreased its generating output according to the reduced demand; however, it still needed to recover fixed costs, thus resulting in an increase in cost per kilowatt to the consumer. In an attempt to reconcile the problem, the DWP entered into an agreement with five large firms whose buildings and workloads varied considerably. The agreement was to find a viable system in which companies could lower their consumption yet increase their load factor.[42]

Basically, the system was set up to have a central computer monitor the demands of the five buildings by remote controls at each location. During the initial programming, the management and plant engineers of each facility determined a prioritized list of equipment and its corresponding load that could be deferred. A demand load

was then formulated to which both the utility and the consumer agreed. The information was then programmed into the central unit, which then would monitor and compare loads throughout the day. If a peak demand was forecasted which exceeded the predetermined level for a certain building, the plant engineer would be notified. The plant engineer, not the utility, had the option of implementing load shedding.[43]

This manual program proved very successful. The utility was able to better predict its load generating requirements while the companies were able to take advantage of lower rates. The companies also obtained an added benefit in the way of energy conservation measures. Several of the facilities were constructed in the early 1900's and had many changes occur that added undue electrical loads to the buildings. While identifying each circuit load, the plant engineers found many circuits with oversized loads or ones which were no longer necessary. Changes were made to eliminate these unnecessary loads and enable the plant engineers to more closely evaluate the entire building. This system provided reports that management used to implement load control and conservation measures to further reduce electricity costs.[44]

There are other load control systems available; however, some are still in the experimental stages while others are not used widely enough to have any significant impact on load control. The technology available today makes direct control and communications the most desirable aspects to limit peak demands. Most systems use a mixture of the various load control and communications systems and some

thermal storage systems. The most desirable aspect of an LCC system is the ability of the utility to exercise direct control, thus more efficiently utilizing its resources.

CHAPTER V

CUSTOMER APPLICATIONS OF LOAD MANAGEMENT

Load management can be applied to the end use of electricity in various ways. Utilities considering various load management systems must evaluate the possible loads to be controlled and their potential impact on the system. Controllable loads vary with each location in the U.S. due to the types and saturation in the region. Residential, agricultural, commercial, and industrial loads vary according to the end use of electricity. Some of these demands have two basic requirements in common, water and space heating, and air conditioning (this does not include agricultural). This chapter examines the various loads which should be considered for load management. Other possible loads may exist which are unique to a manufacturing process or geographical area.

5.1 Residential Electrical Loads

Basic residential loads that may be controlled are water heating, space heating and air conditioning, and swimming pool pumps. All of these electrical requirements vary due to daily as well as seasonal changes. Electric water heaters are an ideal load because of the built-in energy storage capacity of the unit. Heating and air conditioning become more of a control problem depending on the region of the U.S. where it is required. Average load profiles for various end uses are depicted in Figures 11, 12, and 13.

By far the most widely used method of load control is the use of radio systems to defer electric resistance water heater use. Numerous

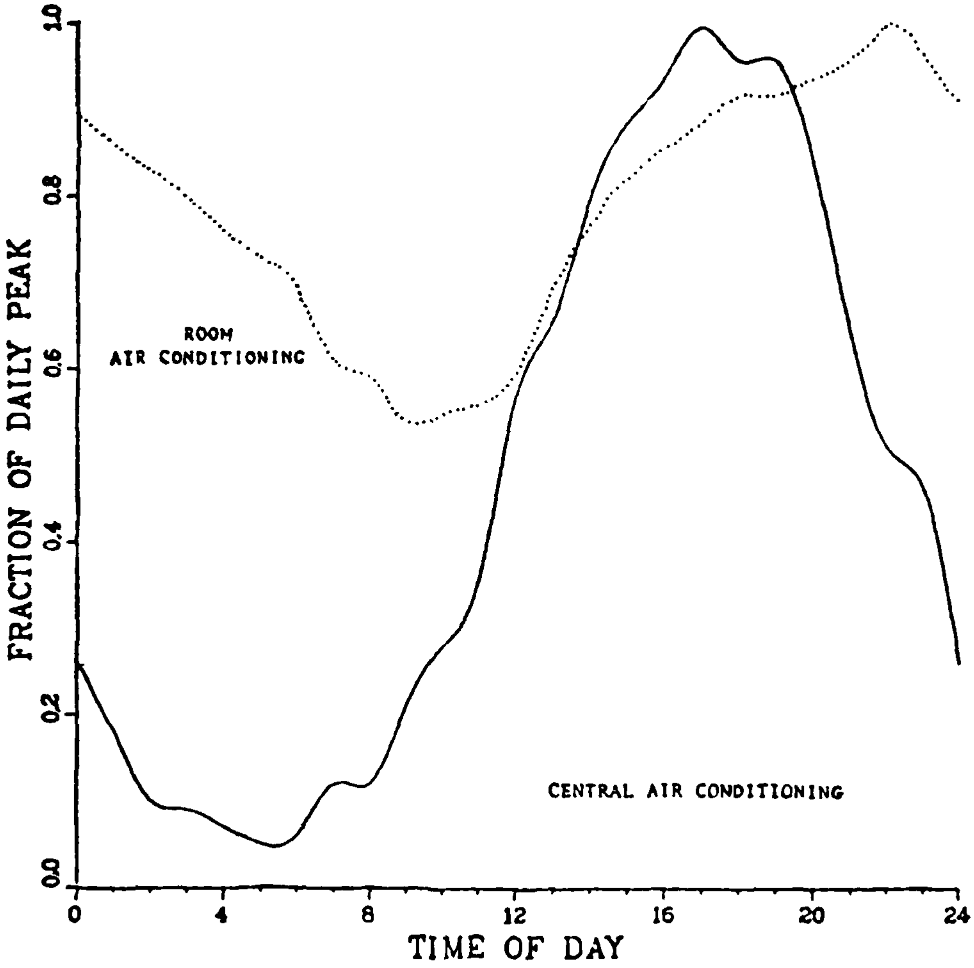

Figure 11. Load Profiles, Residential Air Conditioning

(Source: Analysis of the Need for Intermediate and Peaking Technologies in the Year 2000, Decision Focus Inc., Palo Alto, CA, April, 1980, p.E-2)

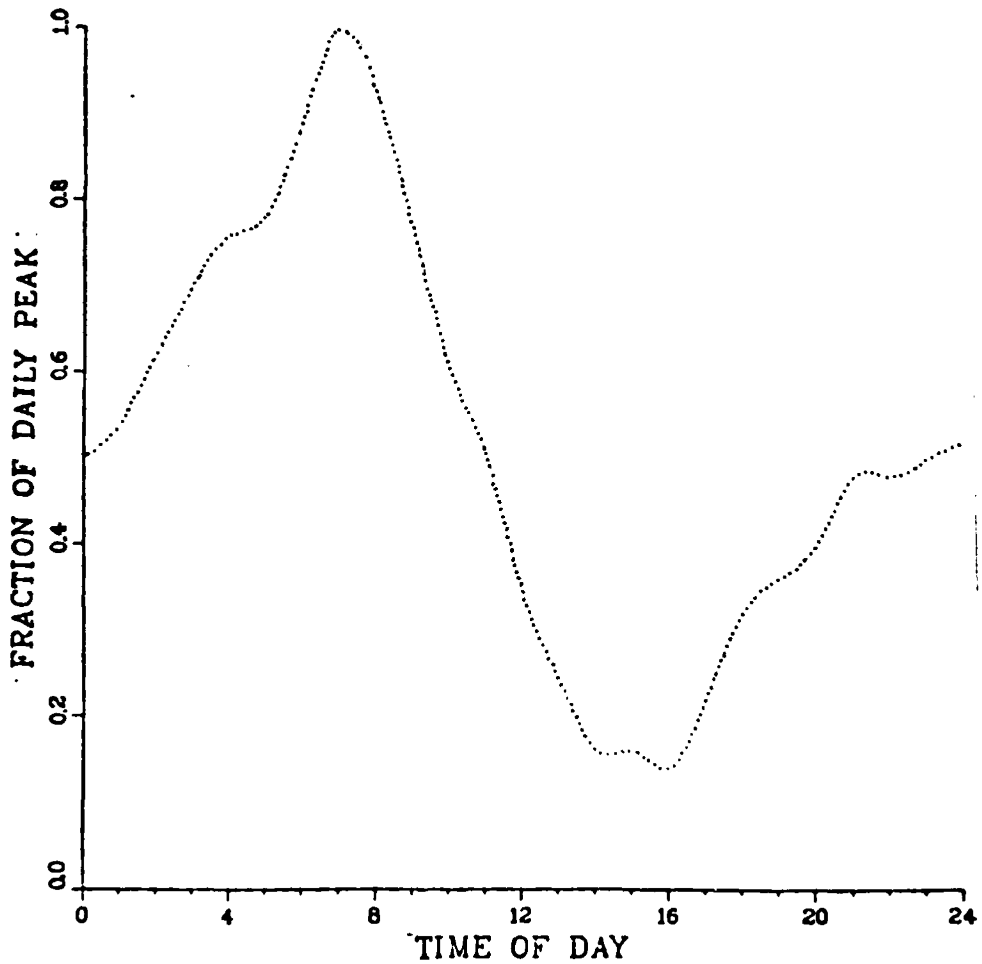

Figure 12. Load Profile, Residential Space Heat

(Source: Analysis of the Need for Intermediate and Peaking Technologies in the Year 2000, Decision Focus Inc., Palo Alto, CA, April, 1980, p.E-1)

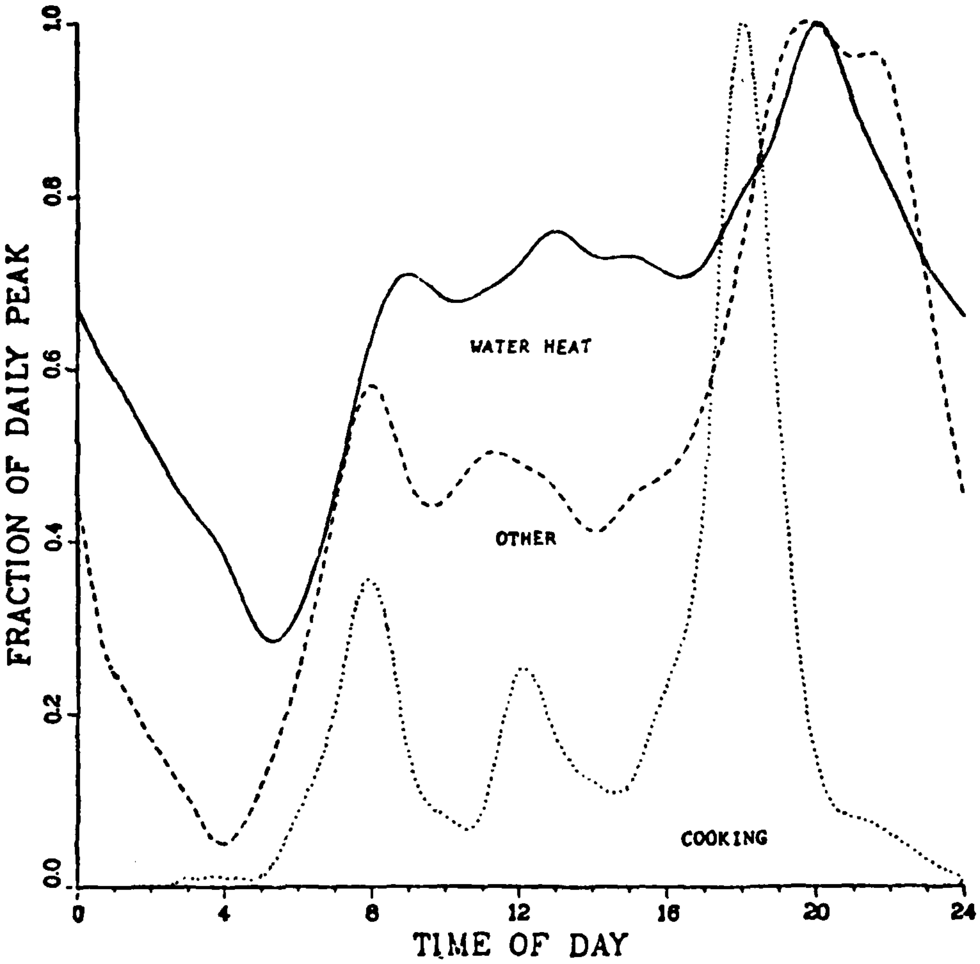

Figure 13. Other Load Profiles, Residential Sector

(Source: Analysis of the Need for Intermediate and Peaking Technologies in the Year 2000, Decision Focus Inc., Palo Alto, CA, April, 1980, p.E-3)

utilities have implemented this type of program and have found that an average 1.1 kW per water heater could be deferred during peak periods. One of the advantages in deferring these loads is that the utilities do not lose revenues. The returning loads after peak loads help to even out the lower valleys and thus increase the load factor. This levelling effect decreases the utilities' costs by using less peaking units at high costs.

Space conditioning is another controllable load, however, quantification of energy savings is difficult to perform. Various factors such as geographical location, seasonal temperatures and humidities, types of homes, type of heating units, and consumer acceptance of controls make this load management option more difficult to evaluate. Utilities may consider the thermal energy storage alternative in order to overcome some of these difficulties.

Arkansas Power and Light Company conducted a test in the Little Rock area in 1975 to determine the impact of air conditioning load management. Radio units were installed in about 300 homes to control the compressors and outside fan units on air conditioners. The tests were conducted between June 15 and September 15. During the test, the units were shut off for periods of 5 to 9 minutes twice each hour when outside temperatures reached 85 degrees F. It was found that the peak coincident kW drop per air conditioner was about 1.2 kW. Responses from the customers indicated that only about 20 percent of them felt any temperature changes after the remote controls were installed.[45]

Swimming pool pumps can be controlled directly or indirectly. One of the easiest indirect methods is the use of a preset timer.

Cooking requirements are difficult to defer; however, these appliances can be locally controlled by means of a priority relay, or interlock. The interlock is a device which is designed to limit the maximum demand by preventing two or more high load appliances from being used at the same time. The device operates by monitoring the current draw on a priority, or non-interruptible, load by means of a current transformer. When the priority load is turned on or when the current draw of a priority load exceeds a preset maximum, the device cuts off power to an interruptible load. An example of priority loads are dryers, stoves, and ovens. When the priority load is turned off, power is restored to the interruptible load. Results from one utility employing these devices found that when a 5 kW dryer was interconnected with a 4.5 kW water heater, an average peak non-coincident demand reduction of 1.5 kW resulted. The installed costs of one of these devices is about $60. It should be noted that the use of these devices may not effectively reduce peak demands upon the utility, depending upon the demands of other appliances in the household.[46]

Even though load management is administered in a voluntary way, it is important for the utilities to insure that discomfort or inconvenience be kept to a minimum. Although a utility may develop an optimal demand reduction schedule, it may be necessary to adopt a more conservative one in order to avoid hints of overcontrol. Residential load management incentives may take the form of a flat credit to the customer for each device installed or separate metering may be used with time of use rates.

5.2 AGRICULTURAL ELECTRICAL LOADS

One load which is region specific is irrigation pumping. In the mid and southwest, irrigation pumping constitutes a major component of a utility's total load. One utility, Southwest Public Power District in Nebraska, estimated that about 85 percent of its summer peak demand was due to irrigation. Many other utilities had similar high loads and began to implement load management programs. Basically, the utilities offered various cost incentives based upon rate schedules and varying levels of control. The logic was to let the farmer decide which rate level he wanted to operate with, weighing the cost incentives with potential crop reductions. An example of the rate schedules offered by a Nebraska utility is shown in Figure 14.[47]

Kansas and Nebraska have the largest known concentration of pump controls, although many other states have installed control methods. Nebraska has a reported 126 MW under direct control, using time clocks, ripple, and radio systems. Other utilities have similar large loads under direct control. Data from the utilities report an average coincident diversified demand reduction of 15 kW per point of control. The results also show that there is no apparent reduction in crop yield. Irrigation load management has shown tremendous success for both the farmer and the utility.[48]

5.3 COMMERCIAL ELECTRICAL LOADS

Commercial electrical loads are similar to residential loads. Commercial activities have additional loads that increase their demand, which includes lighting and other non-essential loads. Non-essential loads vary; however, they generally consist of business

No Control

First	200 kWh per hp at 8.0¢ per kWh
Next	300 kWh per hp at 2.8¢ per kWh
All excess	kWh at 2.0¢ per kWh

Weekly Control (controlled only on a selected day of the week)

First	200 kWh per hp at 5.0¢ per kWh
Next	300 kWH per hp at 2.8¢ per kWh
All excess	kWh at 2.0¢ per kWh

Daily Control (controlled on any day and probably more than 1 day per week)

First	200 kWh per hp at 5.0¢ per kWh
Next	300 kWh per hp at 2.0¢ per kWh
All excess	kWh at 1.5¢ per kWh

Figure 14. Electrical Rates for Irrigation With and Without Load Management

(Source: Evaluation of Load Management Systems and Devices, EUS Inc., Pittsburgh, PA, June, 1980, p.1-13)

equipment and ventilation systems. High commercial demands begin to occur towards the end of the morning peak residential loads and begin to decline towards the evening hours. Retail stores may not follow this trend depending upon the hours of operation. Commercial loads are generally lower on weekends, but this may also depend upon operations.

Utilities may want to consider commercial load management systems for areas with large concentrations of commercial activity. Basic loads to first be considered would be water heating and heating and air conditioning. As discussed in the previous chapter, large commercial buildings may find that non-essential loads may be deferred without any discomfort to the occupants. Retail stores may be able to discover adequate lighting levels which significantly reduce total electrical usage. Ventilation systems offer a type of deferrable load which may be directly or indirectly controlled by the utility.

Government office buildings are large consumers of electrical energy. Although government offices have considerably curtailed energy usage, utilities may want to consider load management agreements which may help the government to identify deferrable loads. One disadvantage to the utility is that if a load is deferred in the afternoon, the revenues may not be recovered at all. In terms of conservation, this would be a favorable operation.

5.4 INDUSTRIAL ELECTRICAL LOADS

Experience of the electric utilties indicates that the industrial sector peak loads coincide with the system peak loads. Because of the diverse nature of industrial electrical loads, it is imperative that each type of industry be examined separately to determine its

impact on load management. Several studies have been conducted to highlight certain options available to both the utilities and the industries in order to conserve energy. The industrial sector has a high potential impact on peak loads. For example, the Detroit Edison Company found that residential consumption represented about 30 percent of the total electrical energy consumption and about 24 percent of peak demand generating requirements. The industrial customers, however, accounted for 50 percent and 36 percent respectively, in these categories.[49]

In the Detroit Edison load management survey, 40 industrial customers were selected which represented 10 standard industrial codes as follows:

1) Food Products
2) Paper Products
3) Printing and Publishing
4) Chemicals
5) Rubber Products
6) Glass Products
7) Primary Metals
8) Fabricated Metals
9) Machinery
10) Transportation

The customers were selected based upon relatively small amounts of energy usage, 6000 kW or less. These customers generally were small and of medium size representing about 90 percent of the total primary industrial customers of the system. In evaluating the customers, the desire of the survey was to direct efforts to 1) high payoff non-capital

requirement projects 2) limited capital requirement projects and 3) capital intensive projects. In order to perform the survey, the utility required complete knowledge of the manufacturing process, including plant equipment and electrical transmission systems to the equipment. The survey also examined lighting systems, HVAC system improvements, building insulation, and heat recovery operations.[50]

Test customers were first surveyed to determine which loads might be controlled. Table 5-1 provides a summary of major electrical use. The miscellaneous uses consisted of water heating, air compressors, forklift chargers, pollution equipment, computers, vent pumps, and other various uses.

The results of the survey found that the proposed changes could result in a 7.4 percent reduction in peak demand. In addition, it was found that a net reduction in kWh/month/customer of about 4 percent could be achieved if the energy saving methods were implemented. Of the total 4 percent reduction, approximately 56 percent was from on-peak and 44 percent was from off-peak. The maximum reductions were from lighting (87%), processing (11%), miscellaneous (10%), while an increase of about 8 percent was expected in HVAC due to system modifications. The increase in HVAC electrical loads was due to conversion of oil and gas to electrical systems. The overall effect of the program was to reduce generating capacity requirements by 31 MW.[51]

Many of the changes that were recommended to the industries did not involve direct control of electrical loads by the utility. The following paragraphs provide a general summary of the recommendations:[52]

Table 5-1 Major Electrical Uses of the Test Companies by Specific Areas in 1975

Area	Estimated kWh %	Estimated kW %
Lighting	15	7
HVAC	6	6
Processing	73	84
Miscellaneous	6	3
Total	100	100

(Source: Project to Demonstrate Potential Energy Savings From Industrial Customers, Michigan Department of Commerce Public Service Commission/Detroit Edison Co., June, 1978, p.16)

1) Timing and control devices: these include timing and control devices on water heaters, battery chargers, lighting systems, heat pumps, air conditioners, and ventilation systems.

2) Demand control systems

3) Heat recovery techniques from manufacturing processes

4) HVAC system improvements

5) Recovery of process and boiler water

6) Lighting modifications

7) General maintenance

8) Insulation

9) Off-hour audits and shift changes

One of the advantages in controlling industrial electrical loads is that most factories already have dual metering systems installed. This allows the utility more flexibility in determining rate schedules for industrial customers. In order to implement some of the load management systems, utilities may offer such incentives as time of use rates, low interest capital loans, tax breaks, subsidies, energy audits, training programs, and development of energy management programs to assist in design of new facilities. The overall effect would be to help raise the industrial load factors.

CHAPTER VI

METHODOLOGIES FOR ASSESSING LOAD MANAGEMENT

Load management can provide significant impacts on both the utility and the customer. Rate price changes associated with load management can affect both customer consumption and utility investment decisions. Load management strategies are dynamic and need continuous updating to insure optimum load factors are sustained. West German utilities had to reevaluate their load management systems when storage space heaters began creating a new peak in the early morning hours due to lower off-peak rate schedules.

The basic idea underlying load management is to control and reshape customer loads. As a strategy in power systems planning, load management offers the following economic benefits:

1) A reduction in the growth rate of the utility's peak loads with a corresponding reduction in generation, transmission, and distribution capacity from what would otherwise be required.

2) Improved daily load factors, allowing substitution of base load generating plant and fuels for peak and intermediate load generating plant and fuels.

3) A reduction in the cost of electricity supply.

Costs for a utility implementing a load management program generally consists of the study costs, load management equipment costs, implementation, and additional operations and maintenance costs. Benefits derived from implementation include those outlined in the preceeding paragraph as well as social and environmental benefits.

Social benefits may consist of the customer's positive attitude towards energy conservation while environmental benefits could be related to the reduction in pollution due to decreased electrical generation. There are numerous qualitative benefits to be derived from load management that may be included in a feasibility evaluation.

6.1 FACTORS INFLUENCING LOAD MANAGEMENT

An evaluation of the attractiveness of load management requires that many factors be considered. The cost effectiveness of any load management option depends upon utility characteristics, customer characteristics, equipment, institutional characteristics, and regulatory factors.

6.1.1 Utility Characteristics

The basic motivation for a utility to implement a load management option is to reduce costs through increased utilization of existing facilities. The utility should examine its load characteristics to determine daily or seasonal variations. The costs associated with these variations should be determined.

The generation mix plays an important role in the cost effectiveness of load management. A variety of generating technologies in the electric system can help to optimize load management and reduce marginal costs for generating electricity. Maintenance requirements associated with the overall system should also be considered. During maintenance periods, the system risk levels are increased and energy costs may increase when base load equipment is off-line. The transmission and distribution requirements may also change with the load management program.[53]

6.1.2 Customer Characteristics

The type of appliance and system saturation will greatly influence any load management option. A utility should determine the potential size of the controllable load, and also develop various scenarios to be used in the evaluation. The total impact is sensitive to the customer's acceptance of load management. The utility should evaluate this sensitivity to the forecasted appliance saturation.[54]

6.1.3 Load Management Equipment

The costs and problems associated with load management equipment was discussed in a previous chapter. Load management options should be developed with those problems in mind. The technology of load management is progressing so rapidly that some of the problems may be eliminated and costs may be lower. A utility may want to examine the possibility of deferring load management in the hope that technological advances will produce a less costly piece of equipment.[55]

6.1.4 Institutional Characteristics

Ownership and financing of load management, socioeconomic consequences, and customer acceptance are some examples of institutional characteristics. It is in the best interests of the utility to own the load management equipment because it can then provide uniformity within the system and develop its own maintenance program. Financing may become a problem if the initial costs are relatively high and funds for such a capital investment are not available. Another problem is the fact that many customers do not understand load management, making voluntary implementation difficult. In addition, if the utilities require the customer to purchase the device, many customers will forego load management even though lower electrical rates are offered.

Some industrial and commercial customers may not find load management beneficial if their return on investment rate is higher than that assumed by a utility in a load management study. The payback period may not be within the customer's allowable limits. Consumers may not desire to have their consumption regulated at all, despite assurances from the utility that inconveniences will be minimal.[56]

6.1.5 Regulatory Factors

Rate structures have a significant impact on the economic success of load management; however, this aspect is very difficult to quantify. There are many costs contributing to a load management program. In order to recover these costs, the utility must attempt to develop a rate schedule that will include these costs. The difficulty lies in keeping the rate schedules fair and understandable. Some utilities have attempted to do this by simply offering a small rebate per month rather than implementing various time of use rates. If a utility desires to use time of use rates, then it must consider the long range electric rates that should be developed to insure customer acceptance in the future.[57]

6.2 TECHNIQUES FOR ASSESSING LOAD MANAGEMENT

The scope of any load management program must first be defined in order to begin any evaluation. The scope and level of detail will mainly be limited by the availability of time, money, and manpower allotted to the study. In order to perform a fairly complete study, adequate computer facilities and compatible software must be available for use. If historical data are not available for loads to be studied, then additional work will have to be done to simulate load models in order to estimate the effect of load management on load profiles.

Once the scope has been determined, the most important result to be obtained from the study is the cost-benefit ratio for each option. The specific benefits and costs should be identified and attempts made to quantify each. Some variables which may be considered are as follows:

Benefits

1) Generation, transmission, and distribution capacity savings
2) Fuel consumption savings
3) Increase in system reliability and reserve margin
4) Increase in spinning reserves

Costs

1) Storage equipment costs
2) Control and communication equipment costs
3) Metering costs
4) Maintenance scheduling effects
5) Loss in quality of customer service
6) System study and implementation costs

Once the costs and benefits are identified, the study horizon, or period of analysis, should be chosen. This determination is basically whether the analysis is for long-run or short-run impacts on the system. A short-run impact study would probably neglect future generation mix and focus on immediate implementation costs and fuel consumption. A long-run impact study would evaluate future generation expansion along with rate schedules and transmission and distribution problems.[58]

Several private firms have developed computer based systems that can evaluate the costs and benefits of various load management options. These techniques vary in their approach to the cost models. Basically, either marginal or total system costs are evaluated. One of the marginal cost methods recommended by the Electric Power Research Institute (EPRI) is the Gordian Associates methodology while the total system cost method is the Systems Control, Inc. methodology. The marginal cost analysis is a fairly quick way to evaluate various load management options to obtain the rough costs and benefits associated with each option. The total cost method is more complex and time consuming; however, it can be cost effective if only one load management program is being evaluated.

6.2.1 Marginal Cost Method for Load Management Assessment

The procedure for calculating the marginal costs of load management are outlined below and shown in Figure 15.

Step 1. Develop the baseline forecast for the utility's hourly load profile.

Step 2. Calculate the marginal costs of service for the study horizon. A number of methodologies have been developed to derive these marginal costs. The Gordian Associates method will be discussed in a subsequent section.

Step 3. Specify the load management program for analysis. The physical and economical aspects of the program should be specified. Physical aspects include the number of control devices to be installed and their impact on the load profile. The economical aspects include the cost of controls and installation, including the central unit and any other supporting equipment.

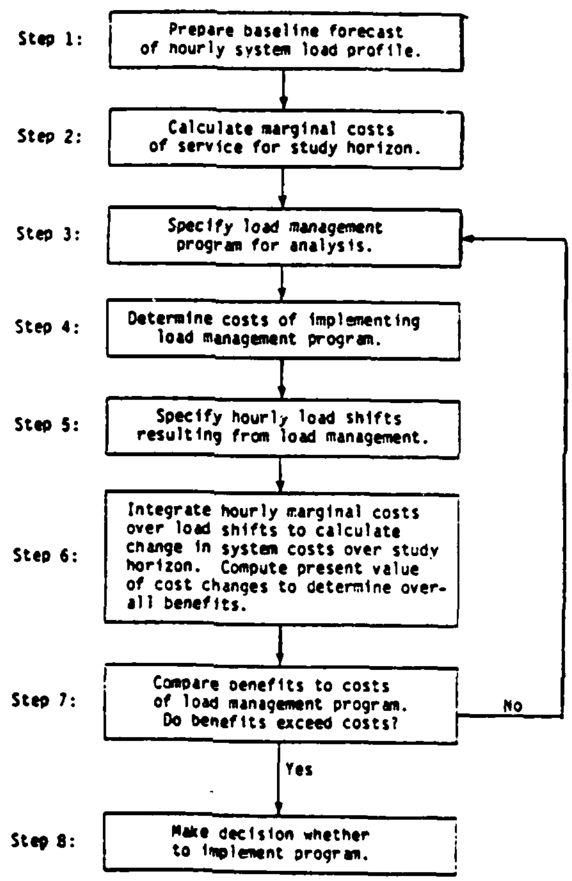

Figure 15. Marginal Cost Method for Load Management Assessment

(Source: Handbook of Five Methodologies for the Assessment of Load Management, Argonne National Laboratory, February, 1980 Exhibit II-1)

Step 4. Determine the costs of implementing the load management program. This step compiles the costs of Step 3. and also derives a present worth value of replacement equipment in future years.

Step 5. Specify the hourly load shifts resulting from load management. This step evaluates the physical aspects from Step 3. The total hourly load shift is found by multiplying the individual load shifts per control device by the number of devices in the system. This gives a 24 hour step function load profile.

Step 6. Integrate the hourly marginal costs over the load shifts to calculate the change in system costs over the study horizon. The change in load from Step 5. is multiplied by the marginal costs in Step 2. on an hourly basis. The annual cost savings are then computed to a present worth value to determine overall benefits.

Step 7. Compare the benefits to the costs of the load management program. The present worth values for both the costs and benefits may be evaluated. If the benefits do not exceed the costs, another load management alternative may be selected and the process repeated beginning with Step 3.

Step 8. Make a decision whether to implement the program. If the benefit-cost analysis appears favorable, management should make the final determination based upon customer acceptance, quality of service, and revenue availability. These factors are not included in the benefit-cost analysis and require scrutiny at this time.

One major disadvantage to the marginal cost method is that it cannot account for large shifts in loads which may significantly affect the hourly marginal costs. If this happens, then Step 2. has to be reformulated and the entire benefit-cost analysis repeated.

Since large load shifts have not generally been experienced with load management programs, this method does not present any great problems.[59]

6.2.2 Gordian Associates Marginal Costs Methodology

This methodology computes the marginal costs of generation (Step 2. above) based upon existing generating units and planned expansion of generating capacity. The computer model consists of three submodels:

1) A nonlinear simulation of utility operating and reliability characteristics.

2) A linear programming capacity optimization model

3) A financial model developing financial statements and ratios.

The first simulation runs plant mix combinations many times using a 10 to 15 year life cycle. The plant mix combinations take into account daily load curve characteristics, plant capacities, variable operating costs, forced outage rates, maintenance schedules, and reliability criterion for the utility. The plant mix combinations are selected to cover a range of possible expansions which may be planned for the future. The simulation determines the availability of each unit as a function of the plant mix and gives the reserve margin as a function of the projected plant mix and unit sizes. Upon producing the system expansion plan, the simulation supplies this information to the linear programming optimization model.

The linear program solves the equations provided to arrive at the solution of the objective function. The solution is the least cost present value of all system generation costs, including capital and running costs, over the life cycle evaluated. When an optimal

cost is obtained, the generating mix is then supplied to the simulation program to undergo a more in-depth evaluation of the costs on an hour by hour generation mix basis. It is from this last simulation that the marginal capacity costs are formulated. Gordian cautions that the marginal capacity costs are coming from the costs of the unit which is carrying the incremental load, and this unit may not be the most expensive unit in the generation capacity.

When the linear program determines that additional capacity is required, the solution gives the net cost of adding the last unit of capacity in order to maintain the same reliability in the system. This net marginal capacity cost is the gross marginal capacity cost less the energy savings resulting from replacing existing higher cost units with newer, less costly, units.

After the expansion plan has been developed, the program derives critical financial ratios for evaluation. If the financial ratios are unacceptable, then the financial ratio constraint may be added into the linear program and the optimization process repeated.[60]

6.2.3 Total Cost Method for Load Management Assessment

The procedure for calculating the total costs of load management are outlined below and shown in Figure 16.

Step 1. Prepare a baseline forecast of the hourly system load profile. These hourly profiles should include the long range demand and energy forecasts.

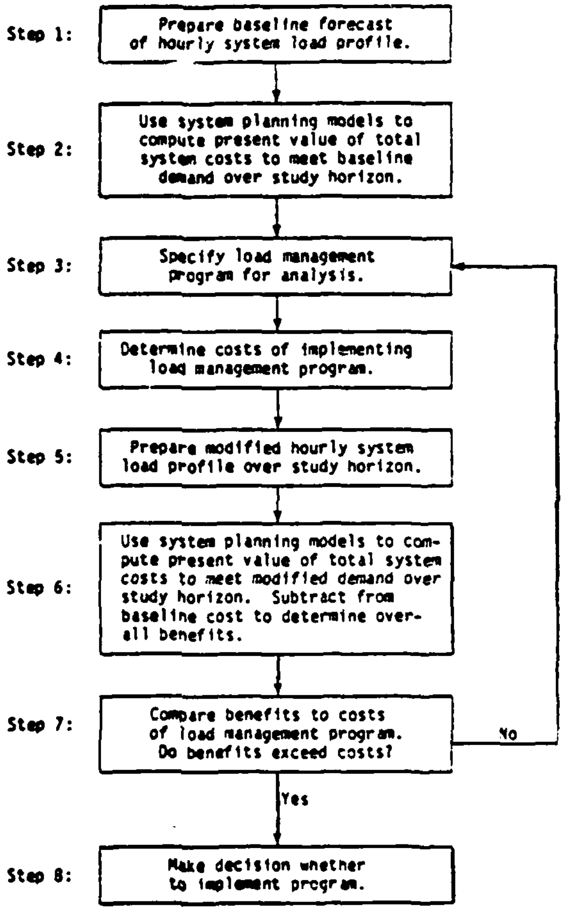

Figure 16. Total Cost Method for Load Management Assessment

(Source: Handbook of Five Methodologies for the Assessment of Load Management, Argonne National Laboratory, February, 1980, Exhibit II-3)

Step 2. Use the system planning models to compute the present worth value of the total system costs to meet the baseline demand over the study horizon. The short-run operating costs of existing generation units can be estimated by production models, while the long-run capital expenditures associated with adequate additional capacity can be estimated by a capacity expansion model. Systems Control, Inc. has developed a program that will calculate these total costs.

Step 3. Specify a load management program for analysis. This step is identical to Step 3. in the marginal cost model.

Step 4. Determine the costs of implementing the load management program. This process is identical to Step 4. in the marginal cost model.

Step 5. Prepare a modified hourly system load profile for over the study horizon. This load profile is slightly different from Step 5. in the marginal cost model in that it provides a smooth load profile rather than an hourly step function resulting from aggregate shifts.

Step 6. Use the system planning models to compute the present worth value of total system costs to meet the modified demand over the study horizon. This step essentially duplicates Step 2. above, however, it calculates the total system costs using the modified load profile and the same degree of generation reliability. The benefit of the load management program is the difference between the costs in Step 2. (baseline) and the costs in Step 6. (modified).

Step 7. Compare the benefits to the costs of the load management program. If the benefits do not exceed the costs, then an alternative load management program may be selected, and the process repeated.

Step 8. Make a decision on whether to implement the program.

The total system cost method is advantageous to use because it can take into account large shifts in load profiles due to load management. This method may not be cost effective if numerous alternatives are to be studied. In this situation, the benefits derived from Step 6. for each alternative first have to be developed from new capacity plans and production costing simulations.[61]

6.2.4 Systems Control, Inc. Total System Cost Methodology

This methodology derives the total system costs as outlined in Step 2. and Step 6. above by using five submodels in sequence. The submodels are described below.

1) Load shape modification program (LSM)

2) Optimal expansion program (OEP)

3) Production costing model (PROCOS)

4) Transmission planning program (TRANSPLAN)

5) Distribution planning program (ACORN)

The LSM model simulates the load changes which result from the control of one or more devices such as air conditioners or water heaters. Using an hourly system load profile and the characteristics of the devices to be controlled, the model constructs a modified hourly system profile. The model can take into account both direct control devices and fixed schedule devices such as time clocks. The model first accounts for the indirect control devices, then optimizes the direct control devices to obtain a maximum peak load reduction. The simulation has the flexibility to vary the control times in order to avoid secondary peaks. The results of the simulation provides a modified load profile.

The OEP evaluates the generation capacity and determines an optimal generating mix. The program can take into account non-thermal generating units such as solar or storage as well as find an economical mix of non-peaking thermal units given a certain load factor. Upon deriving an optimal mix, a reserve capacity is calculated given a certain loss of load probability constraint. In arriving at an incremental cost of generating capacity, the model compares the production costs to the expected load duration curves over a weekly interval.

The PROCOS model simulates the generating operations on a weekly basis. The optimal generation mix derived by the OEP has a priority listing in which to add generating capacity to the system. PROCOS takes into account the expected forced outages for each generating unit, then begins to build the generating capacity up in priority order to fit the load duration curves. After the load duration curves have been satisfied, additional capacity is obtained to meet the loss of load probability criteria.

The TRANSPLAN model can determine the optimal reinforcement plan for the transmission network. It takes into account the need for investment planning on an annual basis. The program presents several alternatives which may be considered to determine the most economical method of transmission network expansion.

The ACORN model can determine the optimum distribution network configuration given constraints such as minimum voltage drop limits, thermal behavior of components, possibility of sectioning the network, and the existence of neighboring support networks which may be used. The model searches for an optimum radial network using the results

from the TRANSPLAN. The results present an annual distribution network configuration given the expected annual growth rates.

The output of the Systems Control methodology provides a total cost for the utility system, consisting of annual capacity additions, fixed costs, production costs, fuel expenses, maintenance expenses, and costs for reinforcements to the transmission network. The results include a modified load profile due to load management and the loss of load probability.

Both the Gordian Associates and Systems Control methodologies are proprietary. Utilities who have used the materials have either leased the software for use on the utility's computer or contracted for the study to be performed by one of the firms. Although there are numerous programs for assessing load management, there are basically two approaches that a method may use, the marginal costs and the total costs methods. Utilities undertaking load management studies may decide how much money will be spent on a study by first determining the number of load management options that are feasible for that area.[62]

6.2.5 Basic Load Management Evaluation Method

A utility may want to make a preliminary evaluation to determine whether further study is merited. The utility's planning staff first needs to assess the impact of load management on items such as system load shapes, generation mix, fuel consumption, revenues, rate design, customer attitudes, and control and communications. Once the data are compiled, a systematic approach may be used to narrow the load management alternatives. This method is fairly simple, and can effectively

eliminate unnecessary options prior to using more complex methods such as the Gordian or Systems approach. An explanation of the method is provided with the following example.

Step 1: Define the scope of load management assessment.

This step specifies the objectives and constraints such as deadlines, forecasting periods, expected results, and funds available for the study.

For this example, Utility A is a medium-size utility that owns two base-load steam generating units and several oil-fired peaker units. The total generating capacity is about 1,220 MW. The utility also purchases wholesale electric power from another utility. The composition of the load is approximately 60 percent rural residential, farm and non-farm, and 40 percent commercial and light industrial. The utility seeks to reduce the peak demands which occur in the winter evenings by about 3 percent. The report is due in one year and management has stated that no alternatives should reduce the quality of service to the customer.

Step 2: Select feasible alternatives.

This step eliminates options which are not suitable for the type of load management or region.

Since the utility has predominantly residential and commercial customers which create a winter peak, the utility will not want to consider air conditioners or industrial loads. Commercial customers generally do not use electric space heating, so control of this load will not be cost-effective. The utility desires to use a central control unit for any type of load management to insure it can effectively control loads during the peak period. With all these considerations,

the following load management alternatives were derived:

1) Remote utility control of:

a) Residential Space heaters

b) Residential storage space heaters

c) Residential water heaters

d) Commercial water heaters and non-essential loads

2) Customer insulation programs

3) Customer energy audits to recommend conservation measures

The control and communications systems to be considered are power line carrier, radio, telephone, and ripple control.

Step 3: Make a rough estimate of the benefits for each alternative.

This estimate may be made by calculating the total marginal costs and savings to be derived from load management. The assumptions, costs, and savings in this example are for the purpose of demonstrating the methodology and do not attempt to represent any industry figures. Any utility using this rather short method will want to vary some of the figures in order to insure that the sensitivity of each variable is ascertained.

Utility A is considering a one-way ripple system to control residential water heaters. Since the utility generates both its own power and purchases it wholesale,two calculations are made to determine the savings of each unit of power. First, estimates are made to determine the power savings, then the associated benefits are calculated.

1) Assumptions

a) Deferred demand at customer site = 1 kW/customer

b) Maximum duration of interruption = 4 hours

c) Estimated deferred demand at time of system peak = 0.7 kW/customer

d)Marginal line losses for transmission = 15%

2) Benefits of reducing wholesale power purchases

a) Monthly demand charge to utility = $7/kW

b) Monthly annuity factor (@12% per annum, this is the utility's investment rate) for an infinite stream of savings = 1/i = 1/.01 = 100.00

c) Net demand deferred at utility metering point for wholesale power [(1.15)(0.7 kW/customer)] = 0.8 kW/customer (The 1.15 includes the 15% line loss)

d) Present value of benefits [($7/kW)(100.00)(0.8 kW/customer)] =$560 /customer

3) Benefits of reducing generation capacity

a) Generation reserve requirements = 20%

b) Net demand deferred from generation and transmission [(1.15)(1.2)(0.7 kW/customer)] = 0.97 kW/customer

c) Cost of generation = $350/kW

d) Cost of transmission = $130/kW

e) Present value of benefits [(0.97 kW/customer)($350 + $130)] = $465/customer

The generation and transmission costs are comprised of various fixed charges such as cost of capital, depreciation, taxes, investment tax credits, and allowances for retirement. The benefits derived above provide a range between which the utility may consider expansion or increased wholesale power purchases.

Step 4: Estimate the cost of each remaining load management alternative.

Utility A must estimate the cost of each control device, the per customer cost of the central control unit, and any additional costs that may be desired, such as the use of a multi-register meter.

1) Cost of control device installed at customer site = $190/ cust.

2) Cost of central control facility = $10/customer

3) Cost of additional metering at customer's site = $250/customer

4) Total costs = $450/customer

The benefit-cost ratios for this example range from 1.03 (465/450) to 1.24 (560/450) for the alternative using a multi-register meter, and from 2.33 (450/200) to 2.80 (560/200) for the alternative without additional meters. The low and high end ratios represent the values for reducing generating capacity and wholesale power purchases, respectively. The utility should now evaluate these ratios to see if they are realistic. After formulating ratios for the various alternatives to be considered, comparisons may be made to further narrow the options remaining. The utility may want to consider combinations of various options of load management as well as plans to include some generation expansion combined with wholesale power purchases.[63]

After step 4., the options to be considered for further study should have been sufficiently narrowed. At this point, the utility can undertake more in-depth studies such as the marginal and total system costs methods previously described. The preliminary analysis can save time in preparing these alternatives for closer evaluations. Two important factors that should be scrutinized in a preliminary analysis is the expected saturation of control devices in the system and the customer incentives or rate schedules required to implement a load management program. A step by step evaluation by various groups within the utility can highlight some potential benefits and problems with a load management option.

CHAPTER VII

CONCLUSION

Since PURPA was enacted in 1978, utilities have been required to investigate methods in which to more effectively utilize their resources. Resources such as fuel and generation capacity have increased in cost to the point where utilities are finding it more difficult to provide electric energy and still maintain system reliability. One of the largest problems faced is the need to provide additional power during brief peak-load periods. This requirement has plagued the electric industry for years and has been responsible for steadily declining load factors. The utilities need ways to improve their load factors.

Load management is a viable option for reducing peak loads for utilities that experience seasonal or daily load fluctuations. In order to implement a program, the utility must first determine the types and saturation of loads within the system that may be controlled. The technology of load management has advanced sufficiently to provide methods of control that are both reliable and minimize customer inconvenience. Solid state technology has provided inexpensive methods which can either directly or indirectly control customer loads. In addition, these new systems may be used to regulate facilities within the distribution system as well as provide remote monitoring capabilities.

Load management options may consist of control and communications systems, thermal energy storage devices, or a combination of both.

The systems may be implemented on a voluntary basis, with incentives such as lower rates, rebates, or tax credits for customers using the program. A load management program can be used by any type of customer depending upon the degree of flexibility and the type of equipment to be controlled.

Utilities that undertake a load management program must first evaluate all possible alternatives prior to implementation. Seasonal, customer, utility, and regulatory characteristics must be carefully weighed during the formulation of various options. In order to defray the costs for preparing the models for study, a utility should first make a preliminary determination of the models and eliminate those that appear to have a benefit-cost ratio less than 1.0. The remaining options may then be set-up for more complex evaluation methods. These more comlex methods can delineate how the system will function and its effect on the peak loads and costs for the utility. Each utility should insure that its own system peculiarities are considered during the evaluation. The computer methods available should give each utility a fairly reliable base upon which the management can choose the best load management alternative.

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